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INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

JOINT PETITION OF INDIANA MICHIGAN POWER COMPANY (I&M) AND AEP GENERATING COMPANY (AEG) FOR CERTAIN DETERMINATIONS WITH RESPECT TO THE COMMISSION'S JURISDICTION OVER THE RETURN OF OWNERSHIP OF ROCKPORT UNIT 2	))))))	CAUSE NO. 45546

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PUBLIC'S
EXHIBIT NO. 1
9-10-21
DATE
AT
REPORTER

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 1

TESTIMONY OF OUCC WITNESS PETER M. BOERGER, PH.D

JULY 29, 2021

Respectfully submitted,

Tiffany Murray
Tiffany Murray, Atty. No. 28916-49
Deputy Consumer Counselor

TESTIMONY OF OUCC WITNESS PETER M. BOERGER, PH.D.
CAUSE NO. 45546
INDIANA MICHIGAN POWER COMPANY AND
AEP GENERATING COMPANY

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Peter M. Boerger, and my business address is 115 West Washington St., Suite 1500 South, Indianapolis, Indiana 46204.

Q: By whom are you employed and in what capacity?

A: I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as a senior economist, with the official job title of Senior Utility Analyst, in the Electric Division. A summary of my educational and professional background, as well as my duties and responsibilities at the OUCC, can be found in Appendix A.

Q: What is the purpose of your testimony?

A: I address the reasonableness of Indiana Michigan Power Company's ("I&M") and AEG Generating Company's ("AEG") (together "Joint Petitioners") joint request for findings from the Indiana Utility Regulatory Commission ("Commission") allowing these entities to purchase Rockport Generating Station's Unit 2 ("Rockport Unit 2") from an owner trust ("Owner Trust"), described in the Petition as "unaffiliated, non-utility institutional equity investors,"[1] that currently owns the electric generation facility.

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[1] Paragraph 12(b), page 4 of Revised Petition.

Q: What specific request do Joint Petitioners make?

A: Joint Petitioners request authority to purchase Rockport Unit 2 by seeking the Commission to either decline its jurisdiction over the proposed transaction or determine the law establishing the Commission's jurisdiction is not applicable to the proposed transaction. Specifically, the revised Petition requests as follows:

> In accordance with Ind. Code § 8-1-2.5-5, Petitioners ask the Commission to decline to exercise its jurisdiction under the CPCN statute with respect to the return of Rockport Unit 2 ownership to Petitioners, or determine that Ind. Code § 8-1-8.5-2 does not apply to the return of Rockport Unit 2 ownership to Petitioners.[2]

I will address each of these requests separately, in reverse order.

II. JOINT PETITIONERS' REQUEST FOR A DETERMINATION THAT IND. CODE § 8-1-8.5-2 DOES NOT APPLY TO THE PROPOSED PURCHASE

Q: What are the requirements of Ind. Code § 8-1-8.5-2?

A: This section states in relevant part:

> . . . a public utility may not begin the construction, purchase, or lease of any steam, water, or other facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service, even though the facility is for furnishing the service already being rendered, without first obtaining from the commission a certificate that public convenience and necessity requires, or will require, such construction, purchase, or lease.[3]

Q: Are Joint Petitioners seeking a Certificate of Public Convenience and Necessity ("CPCN") for the proposed purchase, as required in Ind. Code § 8-1-8.5-2?

A: No. Rather than seek the issuance of a CPCN, Joint Petitioners request the Commission determine compliance with I.C. ch. 8-1-8.5 is not necessary for Commission approval of the proposed transaction.

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[2] Paragraph 22, page 8 of Revised Petition.
[3] I.C. § 8-1-8.5-2.

Q: Are you aware of any basis upon which it would be reasonable to determine I.C. § 8-1-8.5-2 does not apply to the proposed transaction, as requested in the Petition?

A: No. The proposed transaction is a public utility seeking to purchase a facility for the generation of electricity. This type of transaction is explicitly contemplated in the plain language of I.C. ch. 8-1-8.5. There is no clearer indication that the General Assembly, in establishing I.C. ch. 8-1-8.5, sought to regulate the purchase Joint Petitioners are seeking to have ruled outside the Commission's jurisdiction.

Q: Does requiring utilities to obtain CPCNs prior to constructing or purchasing generating facilities protect consumers?

A: Yes. It aids in protecting consumers from paying for unneeded or inappropriate generation investments.

Q: Does the Commission's March 30, 1989, Order granting permission to I&M (and AEG) in its consolidated Cause Nos. 38690 and 38691 to enter into a sale/leaseback arrangement without requiring the issuance of a CPCN have any bearing on this case?

A: No. The Commission's findings in that Order were grounded in I&M's ownership of Rockport Unit 2, along with AEG. The Commission determined I&M did not need to obtain a CPCN because the obligation for the cost of Unit 2 was already held by I&M, and I&M's customers would be responsible for the costs of the Unit regardless of whether the Commission required a CPCN.[4] The key difference in the present Cause is I&M does not currently own Rockport Unit 2 as it did then. Further, at the lease's expiration with the Owner Trust, I&M will not be responsible

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[4] The Commission addresses the applicability of IC 8-1-8.5 in Section 7 of the Final Order in Cause No. 38690/38691, stating in relevant part "The construction of Rockport Unit No. 2 was commenced in 1979, prior to the enactment of IC 8-1-8.5. For that reason, IC 8-1-8.5 clearly does not apply to the construction by Petitioners of Rockport 2, and we see no reason why it should apply to the lease portion of the sale and leaseback of Rockport 2. . ."

for covering AEG's share of the Unit as in 1989, given that AEG will not lease or own Rockport Unit 2's capacity and thus I&M's obligation to AEG under the Unit Power Agreement[5] ("UPA") will no longer apply. As such, the protections afforded to consumers by the CPCN statute are relevant to the current Cause in a way they were not in 1989.

Q: Does the reference in the Petition in this Cause to a "return of . . . ownership"[6] instead of a "purchase" make the requirements of I.C. § 8-1-8.5-2 any less applicable?

A: No. I&M seeks to purchase Rockport Unit 2 from its current owners—the Owner Trust. The document establishing the transaction that is the subject of this Cause is called a "purchase agreement." [7] The fact that Joint Petitioners previously owned the facility[8] does not in any way change the fact that the transaction that is the subject of this Petition is a purchase of a facility for the generation of electricity, thus making the proposed transaction subject to the requirements of I.C. § 8-1-8.5-2.

Q: What do you conclude regarding Joint Petitioners' request for the Commission to determine IC § 8-1-8.5-2 does not apply to the proposed transaction?

A: Joint Petitioners present no reasonable basis to have the Commission determine IC § 8-1-8.5.2 does not apply to the proposed transaction, and I am not aware of any basis beyond what Joint Petitioners presented for such a determination. Having

[5] The Unit Power Agreement, which governs the obligations of AEG and I&M as pertains to Rockport generating units is described in paragraph 12(a) of the Petition in this Cause and was provided to the OUCC in discovery.
[6] See the caption to the Revised Petition in this Cause.
[7] Trust Interests Purchase Agreement attached to the revised testimony of Joint Petitioners' witness Toby L. Thomas as Petitioner's Attachment TLT-2 (Confidential).
[8] As described in Paragraphs 12 through 17 of the Revised Petition in this Cause.

identified that the proposed transaction cannot be reasonably approved based upon inapplicability of IC 8-1-8.5, I next review the reasonableness of approval under Joint Petitioners' alternative approach—that of approval under Indiana's Alternative Utility Regulation statute—IC 8-1-2.5.

III. JOINT PETITIONERS' ALTERNATIVE REQUEST FOR A DECLINATION OF JURISDICTION UNDER IC § 8-1-2.5-5

Q: What is Joint Petitioners' request pertaining to IC § 8-1-2.5-5?

A: Joint Petitioners seek approval for the proposed Rockport Unit 2 purchase through their request that the Commission determine the public interest requires the Commission to decline its jurisdiction over the proposed transaction. Such declination would eliminate the need to obtain a CPCN under IC 8-1-8.5, which I identified in the previous section of my testimony would apply to the proposed transaction.

Q: Is it the OUCC's position the Commission should grant the requested declination under IC § 8-1-2.5-5?

A: No. Granting a public utility the right to avoid requirements of IC 8-1-8.5, while not prohibited under statute, overrides one of the primary protections afforded to public utility customers in Indiana utility law. The OUCC does not see sufficient reason to override those protections in this case.

Q: What reasons do Joint Petitioners give regarding why the protections of IC 8-1-8.5 should be overridden in this case?

A: Most prominently, I&M does not seek cost recovery for the proposed transaction, with the apparent implication customers are not at risk for covering costs from the proposed transaction. Further, Petitioner's witness Mr. Toby L. Thomas identifies a number of benefits to the proposed transaction, including the avoidance of certain "potential disagreements"[9] regarding I&M's obligation to continue operating the facility for the Owner Trust. Included in Mr. Thomas' list of potential benefits is avoidance of potential Effluent Limitation Guidelines ("ELG") compliance costs[10] and potential litigation from the Owner Trust.[11] I&M would also obtain control of 1300 MW of capacity through its ownership of half of Rockport Unit 2 and control of AEG's share of the facility.[12]

Q: Do you agree with an implication that I&M's customers will not face additional risk should the Commission approve the proposed transaction without attribution of cost responsibility?

A: No. First, in my view, granting permission for ownership provides an advantage for I&M in any future request for cost recovery. However, even if cost recovery from I&M's ratepayers is not ultimately granted, I&M's ownership of a large amount of additional capacity (and also, I&M cost responsibility to AEG under the Unit Power Agreement) potentially affects the finances of the regulated utility, how Wall Street views I&M, and ultimately its cost of capital.

Q: Please explain further how I&M having ownership and control of 1300 MW of coal capacity could affect its retail customers, even in the event explicit cost recovery from those customers is not granted.

A: I&M's proposal for approval of ownership without cost recovery approval is in

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[9] P.8, ll.5 Revised Direct Testimony of Toby L. Thomas.
[10] P.8, ll.6-8 and p.12, ll.6-9 Revised Direct Testimony of Toby L. Thomas.
[11] P.9, ll. 13-17 Revised Direct Testimony of Toby L. Thomas.
[12] For efficiency of explanation, I will at points in my testimony refer simply to ownership by I&M rather than providing the more complete reference to "ownership by I&M and control by I&M of AEG's share of Rockport Unit 2." I&M will, through its obligation under the Unit Power Agreement, under Joint Petitioners' proposal, be responsible for the cost of all 1300 MW of capacity, including AEG's share of the facility, even though it would own only 650 MW.

essence granting I&M authority to own 1300 MW of merchant capacity under the regulated utility.[13] Merchant power generators are generally viewed on Wall Street as riskier than regulated utilities because of their lack of government-authorized monopoly status and related lesser level of cost recovery certainty. Granting a simple declination of jurisdiction to I&M to buy half of Rockport Unit 2 (and obligating it to cover costs related to AEG's half of the unit) does not segregate that purchase from the finances of the utility's regulated operations. As such, any losses I&M incurs as a result of obtaining the facility necessarily affect the financial health of the overall company, which includes its regulated operations.

Q: Do Joint Petitioners present evidence as to whether I&M needs the capacity it would obtain through the proposed transaction?

A: No. However, Joint Petitioners stated I&M recently calculated it would need 300-400 MW of capacity at the time Rockport Unit 2's lease expires.[14] This response implies I&M does not need between 900 and 1000 MW of Rockport Unit 2's 1300 MW capacity.

Q: Is the cost of the proposed transaction small enough that its economics can be reasonably ignored?

A: No. Joint Petitioners do not present an economic analysis of the proposed transaction compared to I&M's other options for fulfilling its need for 300-400 MW of capacity. As such, Joint Petitioners have not presented sufficient evidence to judge the extent of the cost and economic risk I&M's customers could face from

[13] Joint Petitioners make this very point on page 5 of their "Joint Petitioners' Response in Opposition to Motion to Dismiss" in this Cause.
[14] See response to OUCC DR 2-3, attached as Attachment PMB-1.

this transaction's approval. While the transaction's $115.5 million[15] purchase price is relatively small compared to the size of I&M's rate base, this asset is proposed to be used and useful for a maximum of only six years.[16] Further, I&M will be responsible for costs to maintain and repair the facility in a manner allowing it to meet PJM requirements as a capacity resource. Thus, the $115.5 million up-front cost does not reflect the true, full costs of entering into this transaction.

Q: Have you performed any calculations to estimate the proposed transaction's economics?

A: Yes. Using data from I&M's most recent six FERC Form 1s (2015 through 2020), I calculated average fixed O&M costs per MW-day.[17] I also calculated the transaction's capital costs on a per MW-day basis over the maximum projected remaining six-year life. Further, I made the additional assumption that I&M would need to cover the cost of ELG upgrades on Rockport Unit 2 in the event the transaction is not approved, as suggested by I&M (and discussed earlier in my testimony).

Q: What were the results of those calculations?

A: I calculate the cost of capacity to be approximately $74 per MW-day when spread over the entire 1300 MW of capacity I&M will obtain. However, as noted above, I&M does not need the full 1300 MW of capacity. Therefore, I also calculated the

[15] P.8, ll.17 Revised Direct Testimony of Toby L. Thomas.
[16] P.3, ll.7 of the Revised Direct Testimony of Toby L. Thomas states that Rockport Unit 2, under Joint Petitioners' proposal will be retired "no later than December 2028," which is 6 years after the expiration of the lease with the Owner Trust.
[17] I calculated costs on a per MW-day basis because these are units used for purposes of PJM's Base Residual Auction ("BRA"), its capacity auction.

cost of this capacity using the midpoint of I&M's estimated capacity needs at the time of the lease expiration (350 MW), which results in a cost of approximately $274 per MW-day.

Q: How do those estimates compare to recent capacity prices in PJM's Base Residual Auction?

A: The results from PJM's most recent auction showed $50 per MW-day capacity prices in the area I&M covers.[18]

Q: Was that value low by historical standards?

A: While it is lower than other recent auctions, the value Joint Petitioners report in a discovery response[19] for the 5-year average of Base Residual Auction results is $106.26—still quite low compared to the cost of the proposed transaction when viewed in the context of the amount of capacity I&M actually needs.

Q: What do you conclude about the proposed transaction's cost?

A: I conclude, at a minimum, the proposed transaction is not a bargain in the context of recent PJM market prices. Further, when viewed in the context of capacity needed to serve I&M's customers, the proposed transaction is expensive.

Q: What do you conclude about Joint Petitioners' request for the Commission to decline jurisdiction over the proposed transaction?

A: I&M does not need the majority of the 1300 MW of capacity it would obtain under the proposed transaction and, based on the capacity that it does need, the proposal is expensive. While Joint Petitioners raise the potential for some risks arising from not allowing Joint Petitioners to purchase Rockport Unit 2 from the Owner Trust,

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[18] See Attachment PMB-2.
[19] See Attachment PMB-3.

they present little support regarding those risks. Given the costs and risk associated with the purchase, the OUCC's position is the public interest has not been shown to require the proposed declination of jurisdiction and thus the OUCC recommends Joint Petitioners' request be denied.

IV. OVERALL CONCLUSIONS AND RECOMMENDATIONS

Q: What are your overall conclusions and recommendations?

A: My analysis shows that neither of the two alternative requests made by the Joint Petitioners (a finding that IC § 8-1-8.5-2 does not apply or alternatively seeking a declination of jurisdiction under IC § 8-1-2.5-5) are reasonable. As such, I must conclude, Joint Petitioners' requested relief is not adequately supported.

Q: While not requested by Joint Petitioners, would it be reasonable for the Commission to grant Joint Petitioners' declination request for only AEG (while not issuing an approval for I&M)?

A: No. Even though AEG does not serve retail customers in Indiana, which may on the surface appear to allow approval for AEG without affecting I&M retail customers, approving the declination for AEG would affect I&M's retail customers as the UPA would require I&M to take the Rockport Unit 2 power from AEG and pay for it under the terms of that agreement.[20] Thus, a declination for only AEG could not be approved without affecting I&M and its customers. While Joint Petitioners are not asking for such a partial result in the alternative, I present this position in the event such a result would become a feasible option for Commission

[20] See Sections 1.2 and 1.3 of the Unit Power Agreement, with a relevant portion of that Agreement attached to my testimony as Attachment PMB-4

decision-making. Thus, as a supplement to my overall recommendations expressed above, I recommend declination of jurisdiction for AEG not be approved on a stand-alone basis.

Q: What do you recommend?

A: I recommend Joint Petitioners' requested relief be denied.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A - QUALIFICATIONS OF PETER M. BOERGER, PH.D.

Q: Please summarize your professional background and experience.

A: My undergraduate education consisted of a Bachelor of Science degree in Mechanical Engineering from the University of Wisconsin-Madison and a Bachelor of Arts degree in Physics from Carthage College, through its 3-2 engineering program. The extra year of liberal arts study during my undergraduate career allowed me to take significant coursework in business and economics, including courses in microeconomics, macroeconomics and accounting. After working as an engineer at a manufacturing company, my graduate training began at Purdue University (West Layette campus) in a program of Technology and Public Policy, resulting in a Master of Science in Public Policy and Public Administration. My training there included courses in microeconomic theory, cost-benefit analysis, operations research (cost minimization algorithms as might be used in utility economic optimization programs), and policy analysis. I came to Indianapolis and worked doing research and analysis at Legislative Services Agency and later at the Indiana Economic Development Council. Following those stints, I began working on my Ph.D. at Purdue University (West Lafayette campus) in Engineering Economics through Purdue's School of Industrial Engineering. That program required taking Ph.D.-level microeconomics classes, as well as additional work in operations research. During my time there I taught a 300-level engineering economy class for three semesters. While finishing my doctoral thesis I worked in policy research for the Indiana Environmental Institute in Indianapolis and then, after obtaining my doctorate, went to work at the Indiana Office of Utility Consumer Counselor, starting as an economist in the Economics and Finance Division. During my 8 years there, I rose to Assistant Director of the Electric Division and then Director of that Division. In 2005 I left the Agency to pursue other interests, largely outside of utility regulation, and then returned in November of 2015 to work in my current position as a senior economist in the Electric Division, with the formal title of Senior Utility Analyst.

Q: Please describe your duties and responsibilities at the OUCC.

A: I review petitions submitted to the Commission for their economic justification and perform other duties as assigned by the Agency.

Q: Have you previously testified before the Commission?

A: Yes, I have testified before the Commission in several significant cases during the 1997 to 2005 timeframe. I also recently submitted testimony in several proceedings since my return to the agency.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 2
IURC CAUSE NO. 45546

DATA REQUEST NO OUCC 2-03

REQUEST

What is I&M's expected capacity shortfall at the time of the expiration of the Unit 2 lease in the event that its proposed purchase of Rockport Unit 2 in this proceeding is not granted? Please identify the basis for and provide calculations supporting I&M's answer to this question, including specific page references to I&M's most recent IRP if applicable.

RESPONSE

For purposes of starting the development of its 2021 Integrated Resource Plan (IRP), I&M identified a capacity shortfall of approximately 300-400 MWs as a result of the expiration of the Rockport 2 Lease. I&M has sufficient capacity to meet its Fixed Resource Requirements (FRR) for the 2022-23 PJM delivery year, due to the availability of Rockport 2 through the entire delivery year (which ends May 2023). I&M has not yet projected the amount of capacity it will require for its FRR for the 2023-24 PJM delivery year, which is the first full delivery year following the end of the Rockport 2 lease, and it is possible that the amount will be higher than the going-in amount identified for IRP purposes. I&M expects this question to be discussed in more detail in Phase Two of the proposed procedural schedule in this matter when the data will be better known and available to all parties.

2022/2023 RPM Base Residual Auction Results

Executive Summary

The 2022/2023 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 144,477.3 MW of unforced capacity in the RTO representing a 21.1% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2022/2023 Delivery Year as procured in the BRA is 19.9%, or 5.4% higher than the target reserve margin of 14.5%. This reserve margin was achieved at clearing prices that are between approximately 19% to 56% of Net CONE, depending upon the Locational Deliverability Area (LDA). The auction also attracted a diverse set of resources, including a significant increase in gas fired combined cycle generation, Energy Efficiency resources and new wind and solar resources.

The 2022/2023 BRA is the third where PJM has procured 100% Capacity Performance ("CP") Resources. CP Resources must be capable of sustained, predictable operation, and are expected to be available and capable of providing energy and reserves when needed throughout the entire Delivery Year. As was the case with the 2021/2022 BRA, the 2022/2023 BRA was conducted under the provisions of PJM's Enhanced Aggregation filing (Docket ER17-367-000 & 001) which was accepted by FERC on March 21, 2017. The 2022/2023 BRA is the first RPM auction conducted under the expanded application of the Minimum Offer Price Rule resulting from FERC's December 19, 2019 Order[1].

2022/2023 BRA Resource Clearing Prices

Resource Clearing Prices (RCPs) for the 2022/2023 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $50.00/MW-day. MAAC, EMAAC, BGE, COMED and DEOK were constrained LDAs in the 2022/2023 BRA with locational price adders, in regards to the immediate parent LDA, of $45.79/MW-day, $2.07/MW-day, $30.71/MW-day, $18.96/MW-day and $21.69/MW-day, respectively, for all resources located in those LDAs. For comparison, the RTO's resource clearing price in the 2021/2022 BRA was $140.00/MW-day. Additionally, the EMAAC, PSEG, BGE, ATSI and COMED LDA were constrained LDAs in the 2021/2022 BRA with RCPs of $165.73/MW-day, $204.29/MW-day, $200.30/MW-day, $171.33/MW-day and $195.55/MW-day respectively.

2022/2023 BRA Resource Clearing Prices

	2022/23 BRA Resource Clearing Prices ($/MW-day)					
Capacity Type	Rest of RTO	MAAC	EMAAC	BGE	COMED	DEOK
Capacity Performance	$50.00	$95.79	$97.86	$126.50	$68.96	$71.69

[1] Docket Nos. EL16-49-000 EL18-178-000 (Consolidated)

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 4
IURC CAUSE NO. 45546

DATA REQUEST NO OUCC 4-05

REQUEST

Referencing Petitioners' response to OUCC DR 2-8 please respond to the following:

a. Please explain how it is that using Rockport 2 as a capacity resource results in "operational efficiencies."

b. Please explain why Rockport 2 is better suited as a "capacity resource" rather than as an "energy resource."

c. Please explain the "current market conditions" referenced in this answer and why those market conditions make Rockport 2 better suited as a "capacity resource" rather than as an "energy resource."

d. Please explain the differences in how Rockport 2 will be operated and managed as a "capacity resource" rather than as an "energy resource."

e. Please explain the differences, if any, as to how Rockport 2 will be offered into PJM's day-ahead energy market to implement Petitioners' intentions to operate Rockport 2 as a "capacity resource" rather than as an "energy resource."

f. What does I&M expect to be the effect, if any, on its margins earned from energy sales resulting from operating Rockport 2 as a capacity resource rather than as an energy resource. Please provide calculations supporting your answer to this question.

g. What does I&M expect to be the effect, if any, on its operations and maintenance cost resulting from operating Rockport 2 as a capacity resource rather than as an energy resource. Please explain why such changes in costs will occur and provide calculations supporting your answer to this question.

h. Does I&M intended to also operate Rockport 1 as a "capacity resource" rather than as an "energy resource?" Please explain I&M's reasoning for its decision on this matter and provide any analysis performed by I&M or on I&M's behalf reviewing this choice and identify how, if at all, this choice was evaluated in I&M's most recent IRP.

RESPONSE

a. The "operational efficiencies" referenced in I&M's response to OUCC DR 2-8 are qualitative efficiencies that are expected to be realized by having both of the Rockport units under I&M's control rather than I&M owning Unit 1 and operating Unit 2 for a different owner or lessee. One example is that the decision making process will be more efficient since it will not be encumbered by the potential for operational or design basis philosophical differences.

b. The reference to a "capacity resource" is acknowledging that the energy value in the PJM day ahead market has declined in recent years due to historically low natural gas prices and the availability of renewable generation. Rockport Unit 2 has the operating

INDIANA MICHIGAN POWER COMPANY
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characteristics and capabilities to be available when other resources are unavailable or insufficient to meet the demand for electricity. In fact, because there are no operational differences between Rockport Units 1 and 2, both are, and will continue to be, available to serve customers when needed.

c. Market conditions determine how resources operate in PJM. Current market conditions indicate that coal resources may create more value as capacity resources rather than from providing energy in PJM. Recent PJM forecasts determined a forecasted Energy & Ancillary Services value of $33.24/MW-Day for an AEP Zone coal unit. When compared to the five most recent Base Residual Auctions (BRA) RTO Zone Clearing price average of $106.26/MW-Day this is a clear indication that capacity value could provide the majority of value created by a coal resource. Rockport 2's large Installed Capacity (1,300 MW ICAP) and favorable performance history, position it to maximize capacity value going forward. Ultimately, economics of energy provision will dictate how often the resource will operate as an energy resource in PJM. AEP currently expects that Rockport 2's primary role will be to operate for energy provision during high load periods or when unusual weather occurs. As a Capacity Resource, Rockport 2 will continue to be offered in compliance with PJM market rules. Energy economics will end up driving the frequency of operation. Natural gas prices, weather, and unit outages all play significant roles in determining how often units operate.

d. See part (b) above.

e. There are no plans to offer Rockport Unit 2 into the PJM day ahead energy market differently unless the Transaction does not close and the Owners direct a different strategy.

f. I&M objects to subpart (f) of this Request to the extent it seeks an analysis, calculation, or compilation which has not already been performed and which I&M objects to performing. Without waiving that objection, please see the response to (e).

g. I&M objects to subpart (g) of this Request to the extent it seeks an analysis, calculation, or compilation which has not already been performed and which I&M objects to performing. Without waiving this objection, I&M states that, since both of the Rockport units will be maintained in a manner such that they will be available to serve customers when needed, O&M savings, if any, would expected to be small.

h. See part (b) above.

AEP Generating Company
FERC Rate Schedule No. 1
Unit Power Service
to
Indiana Michigan Power Company

Tariff Submitter: AEP Generating Company
FERC Tariff Program Name: FPA Electric
Tariff Title: RS and SA
Tariff Record Proposed Effective Date: January 1, 2019
Tariff Record Title: Indiana Michigan Power Company Unit Power Agreement
Option Code: A

UNIT POWER AGREEMENT

THIS AGREEMENT dated as of March 31, 1982 by and between INDIANA & MICHIGAN ELECTRIC COMPANY ("IMECO") and AEP GENERATING COMPANY ("AEGCO"),

WITNESSETH:

WHEREAS, IMECO, a subsidiary company of American Electric Power Company, Inc. ("AEP") under the Public Utility Holding Company Act of 1935 (the "1935 Act"), is presently constructing the Rockport Steam Electric Generating Plant at a site along the Ohio River near the Town of Rockport, Indiana, which will consist of two 1,300,000-kilowatt fossil-fired steam electric generating units and associated equipment and facilities (the "Rockport Plant"), the first unit ("Unit No. 1") of which is presently expected to be placed in commercial operation in 1984 and the second unit ("Unit No. 2") of which is presently expected to be placed in commercial operation in 1986; and

WHEREAS, AEGCO proposes to enter into an Owners' Agreement, dated as of March 31, 1982 (the "Owners' Agreement"), with IMECO and Kentucky Power Company ("KEPCO"), another subsidiary company of AEP under the 1935 Act, pursuant to which AEGCO and KEPCO plan to acquire undivided ownership interests, as tenants in common without right of partition, in the Rockport Plant which, upon completion of the construction of Unit No. 1, is thereafter to be operated as a part of the interconnected, integrated electric system comprising the American Electric Power System (the "AEP System"); and

WHEREAS, AEGCO proposes, upon completion of the construction of Unit No. 1 and the completion thereafter of the construction of Unit No. 2, to make available to IMECO, pursuant to this agreement, all of the available power (and the energy associated therewith) to which AEGCO shall from time to time be entitled at the Rockport Plant; and

WHEREAS, IMECO proposes to complete the construction of, the Rockport Plant pursuant to the provisions of the Owners' Agreement, and, upon completion of such construction, to operate the Rockport Plant pursuant to an operating agreement to be entered into by IMECO, AEGCO and KEPCO in accordance with the Owners' Agreement;

NOW, THEREFORE, in consideration of the terms and of the agreements hereinafter set forth, the parties hereto agree with each other as follows:

1.1 IMECO and AEGCO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.1 and Section 2.2 of this agreement, use their respective best efforts to complete and to make effective the arrangements described and specified in Section 1.1 and in Section 1.2 of the Capital Funds Agreement, dated as of March 31, 1982, between AEP and AEGCO.

1.2 AEGCO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.1 of this agreement, make available, or cause to be made available, to IMECO all of the power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant, including test power produced during the course of the construction of generating units installed as a part of the Rockport Plant.

1.3 IMECO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.2 of this agreement, be entitled to receive all power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant, and IMECO agrees to pay to AEGCO in consideration for the right to receive all such power (and the energy associated therewith) available to AEGCO at the Rockport Plant, as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by IMECO), such amounts from time to time as, when added to amounts received by AEGCO from any other sources, will be at least sufficient to enable AEGCO to pay, when due, all of its operating and other expenses, including provision for the depreciation and/or amortization of the cost of AEGCO's facilities and also including for the purposes of this agreement (i) any amount which AEGCO may be required to pay on account of any interest and/or any commitment fee on all indebtedness for borrowed money issued or assumed by AEGCO (or by any corporation or other entity with which AEGCO shall have merged or consolidated or to which it shall have sold or otherwise disposed of all or substantially all of its assets) and outstanding at the time and (ii) such additional amounts as are necessary after any required provision for taxes on, or measured by, income to enable AEGCO to pay required dividends on any preferred stock which it may issue and such amount as will represent a return on the common equity of AEGCO equal to the return most recently found in the period of the 24 calendar months immediately preceding the time when payments are to commence under this Section 1.3 to be fair, and authorized, by the Federal Energy Regulatory Commission ("FERC", such term also including any successor Federal regulatory agency) as an appropriate return on the common equity of IMECO in a wholesale electric proceeding before FERC under the Federal Power Act, or any legislation enacted in substitution for, or to replace, the Federal Power Act or, if within such period of 24 calendar months immediately preceding the date when payments are to begin under this Section 1.3 no such action by FERC shall have become final and not subject to further proceedings before FERC or a court, the return most recently found to be fair and authorized by the Public Service Commission of Indiana as an appropriate return on the common equity of IMECO in a retail electric proceeding before that Commission. IMECO shall commence the payment of such amounts to AEGCO on the earlier of the following dates: (i) June 30, 1985 and, (ii) the date on which power, including any test power, and any energy associated therewith, shall become available to AEGCO at the Rockport Plant.

2.1 The performance of the obligations of AEGCO hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities at the time necessary to permit AEGCO to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities at the time necessary to permit the completion by IMECO of the construction of the Rockport Plant, the operation of the Rockport Plant, and for AEGCO to make available to IMECO all of the power (and the energy associated therewith) available to AEGCO at the Rockport Plant. AEGCO shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities.

2.2 The performance of the obligations of IMECO hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities necessary at the time to permit IMECO to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities necessary at the time to permit IMECO to pay to AEGCO in consideration for the right to receive all of the power (and the energy associated therewith) available to AEGCO at the Rockport Plant the charges provided for in Section 1.3 of this agreement. IMECO shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities. IMECO shall, to the extent permitted by law, be obligated to perform its duties and obligations hereunder, subject to then applicable provisions of this Section 2.2, (a)

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Peter M. Boerger, Ph.D.
Senior Utility Analyst
Indiana Office of Utility Consumer Counselor

Cause No. 45546
Indiana Michigan Power Co.

Date: July 29, 2021

CERTIFICATE OF SERVICE

This is to certify that a copy of the Indiana Office of Utility Consumer Counselor's Testimony Filing has been served upon the following parties of record in the captioned proceeding by electronic service on July 29, 2021.

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Workpaper PMB-1

Rockport Unit 2 I&M Capacity Cost Analysis

Data from I&M FERC Form 1	2015	2016	2017	2018	2019	2020			
kWh Gen	3,553,403,000	3,148,087,000	3,111,118,000	2,860,105,000	2,073,451,000	1,188,358,000			
Production Expenses - Operations, Supervision, Engineering	$1,976,631	$1,894,884	$1,901,936	$2,421,880	$2,674,550	$1,946,605			
Maintenance Supervision & Engineering	$1,117,073	$1,176,042	$1,080,938	$1,298,207	$1,363,038	$1,207,220			
Maintenance of Structures	$297,785	$172,224	$247,838	$328,571	$178,040	$268,742			
Maintenance of Boiler Plant	$6,201,228	$2,512,623	$2,417,235	$5,785,543	$3,010,029	$1,987,990			
Maintenance of Electric Plant	$1,770,356	$604,470	$575,926	$5,785,543	$750,754	$1,336,350			
Maintenance of Misc Steam Plant	$612,176	$459,035	$511,724	$504,201	$379,689	$334,028			
Total Non-Fuel O&M Costs for only I&M Share of Ownership	$11,975,249	$6,819,278	$6,735,597	$16,123,945	$8,356,100	$7,080,935			
times 2 to reflect both I&M and AEG ownership	$23,950,498	$13,638,556	$13,471,194	$32,247,890	$16,712,200	$14,161,870			
$/MW-day non-fuel O&M costs across 350MW needed in 2023	$187.48	$106.76	$105.45	$252.43	$130.82	$110.86			
Year	2023	2024	2025	2026	2027	2028			
Non-Fuel O&M in Future Year Dollars @ 2% Inflation	$211.13	$120.23	$118.75	$284.28	$147.32	$124.84	$167.76		
Return On (Using I&M's Cost of Capital Grossed Up for Taxes)	$7,981,000	$6,650,833	$5,320,667	$3,990,500	$2,660,333	$1,330,167	Initial Cost:	$115,000,000	
Return Of	$19,166,667	$19,166,667	$19,166,667	$19,166,667	$19,166,667	$19,166,667			
	$27,147,667	$25,817,500	$24,487,333	$23,157,167	$21,827,000	$20,496,833			
"2023 cost of capital investment per MW-day over 350MW	$212.51	$202.09	$191.68	$181.27	$170.86	$160.44	$186.48		
Sum of Non-Fuel O&M and Capital Investment Costs over 350MW w/o ELG offset	$399.99	$308.85	$297.13	$433.70	$301.68	$271.30	$335.44		
Sum Using Average O&M Expenses	$380.27	$369.85	$359.44	$349.03	$338.62	$328.20	$354.24		
Incorporating ELG Cost Offset:									
Year	2023	2024	2025	2026	2027	2028			
$/MW-day non-fuel O&M costs across 350MW needed in 2023	$187.48	$106.76	$105.45	$252.43	$130.82	$110.86			
Non-Fuel O&M in Future Year Dollars @ 2% Inflation	$211.13	$120.23	$118.75	$284.28	$147.32	$124.84	$167.76		
Return On (Using I&M's Cost of Capital Grossed Up for Taxes)	$4,545,700	$3,788,083	$3,030,467	$2,272,850	$1,515,233	$757,617	Initial Cost:	$65,500,000	"($115.5 million less ELG est of $50 million)
Return Of	$10,916,667	$10,916,667	$10,916,667	$10,916,667	$10,916,667	$10,916,667			
	$15,462,367	$14,704,750	$13,947,133	$13,189,517	$12,431,900	$11,674,283			
"2023 capital cost per MW-day spread over 350MW	$121.04	$115.11	$109.18	$103.24	$97.31	$91.38	$106.21		
Sum of Non-Fuel O&M and Capital Investment Costs over 350MW	$332.17	$235.33	$227.93	$387.52	$244.64	$216.23	$273.97		
Sum Using Average O&M Expenses ($/MW-Day)	$288.80	$282.87	$276.93	$271.00	$265.07	$259.14	$273.97		
Spreading Costs over 1300 MW and Not Incorporating ELG Cost Offset:									
Year	2023	2024	2025	2026	2027	2028			
$/MW-day non-fuel O&M costs across 350MW needed in 2023	$50.48	$28.74	$28.39	$67.96	$35.22	$29.85			
Non-Fuel O&M in Future Year Dollars @ 2% Inflation	$56.84	$32.37	$31.97	$76.54	$39.66	$33.61	$45.17		
Return On (Using I&M's Cost of Capital Grossed Up for Taxes)	$8,015,700	$6,679,750	$5,343,800	$4,007,850	$2,671,900	$1,335,950	Initial Cost:	$115,500,000	
Return Of	$19,250,000	$19,250,000	$19,250,000	$19,250,000	$19,250,000	$19,250,000			
	$27,265,700	$25,929,750	$24,593,800	$23,257,850	$21,921,900	$20,585,950			
"2023 capital cost per MW-day over 350MW	$57.46	$54.65	$51.83	$49.02	$46.20	$43.38	$50.42		
Sum of Non-Fuel O&M and Capital Investment Costs over 350MW	$114.31	$87.02	$83.80	$125.55	$85.86	$77.00	$95.59		
Sum Using Average O&M Expenses	$102.63	$99.81	$97.00	$94.18	$91.37	$88.55			

Spreading Costs over 1300 MW and Incorporating ELG Cost Offset:

Year	2023	2024	2025	2026	2027	2028		
$/MW-day non-fuel O&M costs across 350MW needed in 2023	$50.48	$28.74	$28.39	$67.96	$35.22	$29.85		
Non-Fuel O&M in Future Year Dollars @ 2% Inflation	$56.84	$32.37	$31.97	$76.54	$39.66	$33.61	$45.17	
Return On (Using I&M's Cost of Capital Grossed Up for Taxes)	$4,545,700	$3,788,083	$3,030,467	$2,272,850	$1,515,233	$757,617	Initial Cost:	$65,500,000
Return Of	$10,916,667	$10,916,667	$10,916,667	$10,916,667	$10,916,667	$10,916,667		
	$15,462,367	$14,704,750	$13,947,133	$13,189,517	$12,431,900	$11,674,283		
"2023 cost of capital investment per MW-day over 350MW	$32.59	$30.99	$29.39	$27.80	$26.20	$24.60	$28.59	
Sum of Non-Fuel O&M and Capital Investment Costs over 350MW	$89.43	$63.36	$61.37	$104.33	$65.86	$58.21	$73.76	
Sum Using Average O&M Expenses ($/MW-day)	$77.75	$76.16	$74.56	$72.96	$71.37	$69.77	$73.76	